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PUC PROJECT NO. 52373

**REVIEW OF WHOLESALE ELECTRIC
MARKET DESIGN**

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**PUBLIC UTILITY COMMISSION
OF TEXAS**

CALPINE CORPORATION'S RESPONSE TO OCTOBER 25, 2021 QUESTIONS

Calpine Corporation ("Calpine") appreciates the Commission's continued focus on market design reforms to incentivize long term reliability as well as the opportunity to provide responses to the questions below. As an overarching theme, the Commission should delineate separate tracks for reforms that can quickly be implemented in 2022 and longer-term reforms that would best be evaluated in separate projects after scoping and policy direction from the Commission.

The first three questions regarding the Operating Reserve Demand Curve ("ORDC"), existing ancillary services and development of a winter fuel product touch upon market design reforms that the Commission can quickly evaluate and instruct to be implemented in the near term. Questions 4 through 16 regarding the review of Load Serving Entity ("LSE") Obligations and alternatives likely necessitate their own separate project because they will take longer to fully develop and evaluate.

Overall, Calpine continues to believe the Commission must set a reliability standard, and that standard should be a "1-in-10", which previous analysis has shown is created through a 15.75% reserve margin. Furthermore, the Commission must adopt market rules to ensure this standard is met, such as an ORDC shift as well as something like the Reliability Obligation described by Chairman Lake in his memo filed in this Project on October 20, 2021. If an LSE reliability obligation is not adopted, a well-designed firming product could serve as a potential alternative, although ERCOT will remain the sole competitive market in the US without a mandated reliability target.

Response to Specific Questions

1. The ORDC is currently a "blended curve" based on prior Commission action. Should the ORDC be separated into separate seasonal curves again? How would this change affect operational and financial outcomes?

No, the ORDC should not be separated into seasonal curves. Seasonal curves would remove money from the market and depress forward prices which would undermine investment in the ERCOT market. The ORDC is a tool to produce revenue during periods of resource scarcity and spurs investment which not only includes new build but also maintenance and upgrades of existing generation. It also serves to delay premature retirement of older generation assets to ensure long-term resource adequacy. The "curve" is intended to serve as a measure of reliability risk in the ORDC calculation. In 2019 the Commission directed ERCOT to simplify the ORDC calculation by eliminating the seasonal and time of day variation in the Loss of Load Probability ("LOLP") determination. The prior ORDC curve produced twenty-four different ORDC shapes that varied by season and time of day (in four-hour groups). These constant ORDC shape changes added unnecessary volatility without materially improving accuracy. The current single curve reduces the complexity of estimating scarcity pricing in forward price calculations and provides a more consistent signal to support development. Additionally, the average curve can result in slightly higher revenues during peak times when dispatchable generators are online and are paid the ORDC while also producing slightly lower revenues during other times. Investment in the energy only market relies on peak pricing resulting in revenue during peak times. While Calpine recommends retaining the blended curve, if the Commission chooses to return to seasonal curves, that should only happen after an independent analysis is conducted that shows the impact on expected financial outcomes to dispatchable generation. Without such analysis, returning to seasonal curves could have the unintended consequence of financially disincentivizing new dispatchable generation build and could promote early retirement of existing dispatchable generation resources.

The Commission should focus on ORDC parameter changes that will send a positive forward price signal for investment including a shift of the value of X and additional parameter changes consistent with the Commission's desired change to the HCAP that will achieve a 1-in-10 or greater standard.

2. What modifications could be made to existing ancillary services to better reflect seasonal variability?

Calpine supports ERCOT's continued procurement of Ancillary Services at existing levels to support reliability. These reserves are procured through a market mechanism and so no change is needed, other than to make this level permanent. However, the Commission and ERCOT should modify how the costs of these reserves are allocated consistent with Governor Abbott's directive¹ to "allocate reliability costs to generation resources that cannot guarantee their own availability, such as wind or solar power." ERCOT should determine how much of the need for the reserves is created by variability due to load versus generation and split the allocation of the costs on that basis. The costs attributable to generation should be allocated only to intermittent resources that are driving the increased need for the additional reserve procurement. Furthermore, consistent with the increased Non-Spin Reserve Service ("NSRS") procurement by ERCOT, adding a requirement for offline NSRS to also include the same offer floor as on-line NSRS is recommended. This price floor will help ensure that the impact of additional reserves on real-time prices are mitigated.

Additionally, the Commission should evaluate the standards of participation in RRS regarding energy storage. Currently, the standard for storage participation is based on a 1-hour qualification, which has permitted short duration 1-hour batteries to be paid around the clock for RRS despite their actual physical capability being only 1 hour, not 24 hours. Allowing short duration 1-hour batteries to participate in RRS decreases reliability because the service is being provided by short duration resources rather than resources that have the duration to continuously supply energy deployments from RRS. During Winter Storm Uri, energy from RRS was deployed at least four times for durations longer than 1 hour.² In such circumstances, 1-hour battery resources that are awarded may not be able to physically deploy for the duration of the time the resource is released to SCED. Increasing the duration requirement to provide RRS

¹ <https://gov.texas.gov/news/post/governor-abbott-directs-public-utility-commission-to-take-immediate-action-to-improve-electric-reliability>

²

http://www.ercot.com/content/wcm/key_documents_lists/214010/February_2021_ERCOT_Operations_Report_Public.docx

or ERCOT Contingency Reserve Service (“ECRS”) and Non-Spin to at least match the longest RRS deployment experienced during Uri, is recommended. To this end the Commission should review ERCOT’s scheduling and operating procedures to ensure short duration resources are not having a deleterious effect on long term reliability. Alternatively, the Commission may wish to focus enforcement discretion on short duration resources that are offered in back-to-back hours but cannot physically provide energy if released for multiple hours.

3. Should ERCOT develop a discrete fuel-specific reliability product for winter? If so, please describe the attributes of such a product, including procurement and verification processes.

a. How long would it take to develop such a product?

b. Could a similar fuel-based capability be captured by modifying existing ancillary services in the ERCOT market?

Yes, the development of a discrete fuel-specific reliability requirement is recommended, a product could be implemented quickly if the product is kept separate from existing ancillary services (“AS”), and the Commission manages the development process or provides significant direction to stakeholders regarding parameters for development. Key parameters include resource qualification attributes and the amount of capacity that ERCOT should procure through this product and contract period. PURA 39.159(c) provides guidance regarding product qualification including requirements that resources meet continuous operating requirements and have onsite fuel storage, dual fuel capability, or fuel supply arrangements to ensure winter performance for several days. Attributes of fuel supply arrangements should include natural gas plants with multiple pipeline interconnections or firm transport coupled with firm gas from multiple suppliers. Firm gas can be demonstrated by capacity tied to supply from interstate pipelines, capacity tied to storage or other gas supply that has demonstrated surety through past performance. Requirements for verification and testing can be managed through ERCOT Protocols. Moreover, the Commission already prohibits a market participant from offering reliability products to the market that it cannot or will not be provided if selected.³ Market participants should expect the Commission to utilize maximum enforcement authority if generators are awarded for this product and fail to perform.

³ See 16 Tex. Admin Code § 25.503(g)(3).

This compliance hazard should limit participation to resources with a high level of certainty regarding performance.

A fuel-based capability could be incorporated in existing AS; however, there are complications regarding a single clearing price for a premium winter fuel product vs something like Non-Spin with a portion reserved for firm fuel capacity. Creating the process to establish a separate bid-stack in ERCOT systems will delay implementation versus creating a separate process outside the existing ancillary service market. Mirroring the procurement process for Black Start and making the award a multi-season award to create a revenue stream sufficient to encourage resources to procure firm fuel that can be counted on for winter performance is recommended.

4. Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation resources in ERCOT?

In the long term an LSE Obligation is the best means to establish a firming requirement. A multi-pronged approach that includes amending the ORDC to achieve a 1-10 standard, conservatively procuring AS at current levels and assigning some of the costs to the intermittent resources that cause variability through their intermittency may be a workable alternative in the near term. However, longer term, the massive increase in highly subsidized intermittent renewables will adversely impact the economics of firm dispatchable generation. Decreased energy payments to dispatchable generation without offsetting payments for the capacity value they provide will threaten grid reliability unless the ERCOT market structure fundamentally changes. Opening a project to review options including the LSE Obligation to address the negative impacts of federal subsidies on the Texas competitive market is recommended.

5. Are there alternatives to an LSE Obligation that could address the concerns raised about the stakeholder proposals submitted to the Commission?

See response to question 6.

6. How can an LSE Obligation be designed to protect against the abuse of market power in the wholesale and retail markets?

a. Will an LSE Obligation negatively impact customer choice for consumers in the competitive retail electric market in ERCOT? Can protective measures be put in place to avoid a negative impact on customer choice? If so, please specify what measures.

The responses to questions 5 and 6 are together. An LSE obligation will not have a negative impact on customer choice. In fact, it will ensure the continuation of a vibrant competitive market. Nothing will kill competition in ERCOT faster than a lack of dispatchable capacity to cover intermittency. An LSE Obligation provides the Commission and ERCOT a vehicle to set a reliability standard and then put in place an administrative mechanism to ensure that standard is achieved. If there are more resources on the system than necessary to meet reliability, the costs of meeting the LSE Obligation will be low. However, if the system is tight, prices will rise as LSEs contract with resources to meet their obligations, incentivizing new construction.

An LSE Obligation would not be needed if ERCOT had the ability to selectively turn power off to customers whose LSEs have not procured energy ahead of time and were purely riding the Real Time “RT” market. If this were the case, when system conditions were tight, customers of those LSEs who have not procured on a forward basis could be curtailed and there would be enough resources for everyone else. But, this is currently not the case. In today’s world, LSEs can choose not to procure energy on a forward basis for their customers, and when system conditions are tight, ERCOT spreads the curtailment out across the system. For this reason, a forward LSE Reliability Obligation is necessary to ensure the reliability standards are met.

b. How can market power be effectively monitored in a market where owners of power generation also own REPs that serve a large portion of ERCOT's retail customers?

Market power mitigation will be a critical feature, but should not drive the market design one way or another. There is no reason a market power mitigation plan cannot be developed to ensure the competitiveness of the LSE Reliability Obligation. The first step is for the Commission to determine the appropriate market mechanisms to ensure reliability, and then figure out how to ensure those markets are competitive.

Market power is actively monitored in ERCOT's energy market by the Independent Market Monitor ("IMM,") and the larger generation companies have in place Voluntary Mitigation Plans to ensure the competitiveness of the energy market. The Commission has historically managed complex issues including means to mitigate market power through targeted rulemakings. See for example, 25.90 and 25.503. Development of those rules have typically taken a year or longer and the outcomes have been extremely successful. Moreover, all ISOs across the country have addressed these issues through rulemakings.

c. What is the impact on self-supplying large industrial consumers who will have to comply with the LSE Obligation and will it impact their decision to site in Texas?

Industrial resources that can curtail would receive credit because they are essentially self-supplying their own resources to meet the LSE Reliability Obligation, and would thus not need to procure anything further.

d. What is the impact of an LSE Obligation on load-serving entities that do not offer retail choice, such as municipally owned utilities or electric cooperatives?

These entities would need to show they have met their LSE Obligation for their load just like all other LSEs through a combination of owned and contracted-for assets.

e. Can market power be monitored in the bilateral market if an LSE Obligation is implemented in ERCOT? Can protective measures be put in place to ensure that market power is effectively monitored in ERCOT with an LSE Obligation? If so, please specify what measures.

Yes. As noted earlier, the Commission should open a separate Project to specifically focus on market mitigation. Specific items that should be examined include the adoption of behavioral rules potentially similar to the current Voluntary Mitigation Plans in the Energy market, price caps, transparent bulletin boards, market monitor review of transactions.

f. Should the LSE Obligation include a "must offer" provision? If so, how should it be structured?

Yes, and the structure should be developed in a separate proceeding after the Commission has established a reliability standard.

7. How should an LSE Obligation be accurately and fairly determined for each LSE? What is the appropriate segment of time for each obligation? (Months? Weeks? 24 hour operating day? 12 hour segments? Hourly?)

An LSE Obligation with a monthly review is recommended. Because LSE Obligations would be satisfied on a forward basis, LSE Obligations should be based on projected contributions to the need for capacity. The process should work as follows. First, ERCOT would first develop its own aggregated load forecast. Then, LSEs would submit a forecast of the load associated with their customers to ERCOT. ERCOT would then validate the LSE forecasts and ensure consistency with the aggregate forecast, and adjust the individual LSE forecasts for coincidence, i.e., due to the fact that different LSEs may peak at different times, the sum of the LSE peaks may exceed the system peak. These validated forecasts then constitute the basis for each LSE's capacity requirements. Once these requirements are established, there would be limited mechanisms to adjust each LSE's capacity requirements within the month to reflect load migration, i.e., changes in customers not differences between forecast and realized load for a defined set of customers.

8. Can the reliability needs of the system be effectively determined with an LSE Obligation? How should objective standards around the value of the reliability-providing assets be set on an on-going basis?

a. Are there methods of accreditation that can be implemented less administrative burden or need for oversight, while still allowing for all resources to be properly accredited?

The intent of an LSE Obligation is to provide revenues to resources that reflect the true level of reliability they provide to the market through an accreditation process that recognizes the value and dependability of those resources contributions during stressed system conditions. The accreditation process in ERCOT would apply equally to all resources including those contracted by retail electric providers ("REPs"), industrial customers that self-supply, municipally owned utilities and electric cooperatives. The

methodologies for implementing these processes is well developed and should not be difficult for ERCOT or the PUCT to implement with the assistance of a 3rd party consultant.

b. How can winter weather standards be integrated into the accreditation system?

The general framework for calculating the accreditation for intermittent and energy limited resources is called the Effective Load Carrying Capability (“ELCC”) methodology, and it utilizes modeling similar to the modeling used to develop Planning Reserve Margins. ELCC reflects the contribution of a resource to reliability relative to a perfectly reliable resource of the same nameplate capacity. The modeling used to develop ELCCs captures the performance of resources under a broad range of load and renewable generation conditions. Most markets with formal reliability obligations have implemented (California) or are in the process of implementing (New York, New England, PJM) ELCC for renewables and in some cases storage and other resources. By using this methodology, winter weather conditions, standards, and resource performance characteristics can be incorporated into the modeling to determine how various resources contribute to reliability during the season.

9. How can the LSE Obligation be designed to ensure demand response resources can participate fully and at all points in time?

There is no inherent obstacle to allowing demand response (“DR”) to count towards capacity requirements. It will be important to ensure that DR is counted accurately, however, to reflect its energy/use limits, e.g., x hours per month or y calls.⁴

10. How will an LSE Obligation incent investment in existing and new dispatchable generation?

An LSE Obligation, based on ELCC will cause loads to contract with resources that reflect their true capacity value. If there is a deficiency in capacity need to serve load then the forward price for capacity will reflect that scarcity and send a signal to developers to build new capacity.

⁴ For example, CAISO has applied ELCC to DR to capture these limitations. See <http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=2D59FEB8-0CE6-4914-8080-4AE0C7C1E309>.

11. How will an LSE Obligation help ERCOT ensure operational reliability in the real-time market (e.g., during cold weather events or periods of time with higher than expected electricity demand and/or lower than expected generation output of all types)?

Firm, dispatchable resources should only receive full accreditation for meeting an LSE Obligation only if they have weatherized appropriately, have firm fuel, and have reasonable startup and physical dispatchability characteristics. In addition, these resources should have a day-ahead must offer requirement and be subject to significant penalties for non-performance.

12. What mechanism will ensure those receiving revenue streams for the reliability services perform adequately?

The strong performance incentives will be provided by expected high Locational Marginal Prices (“LMPs”) in the real-time market, along with the spot market non-performance penalties. For example, under PJM’s Capacity Performance and New England’s Pay for Performance, LSEs potentially face pay for performance penalties roughly comparable to the ERCOT energy price cap, but those penalties are assessed outside of the energy market and are not reflected in LMPs.

13. What is the estimated market and consumer cost impact if an LSE obligation is implemented in ERCOT? Describe the methodology used to reach the dollar amount.

No comment.

14. How long will the LSE Obligation plan take to implement?

It is expected that development of an LSE Obligation will take at least one year.

15. If the Commission adopts an LSE Obligation, what assurances are necessary to ensure transparency and promote stability within retail and wholesale electric markets?

The Commission should open a separate Project to specifically focus on market mitigation. Specific items that should be examined include the adoption of behavioral rules potentially similar to the current Voluntary Mitigation Plans in the Energy market, price caps, transparent bulletin boards, and market monitor review of transactions.

16. Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO, and Australian markets that could be applied in ERCOT?

The biggest lesson learned is that once government starts picking winners and losers through discriminatory resource procurement or mandates, private investment stops or becomes more expensive because of investor's concerns about future interventions. There is a role for the PUCT to determine a reliability standard, and then adopt market mechanisms that will achieve the goal. However, once the PUCT has adopted a holistic framework, it must let the market signals work and resist the urge to intervene. For example, some are advocating for long-term procurement of firm, dispatchable resources outside of ERCOT's competitive market. This is exactly the path California took in the mid-2000's and, as result, the state is now fully back to a central planning process where all new capacity is acquired only through ratepayer guarantees through the use of long-term contracts or ratebase. The net result is that California regulators make all resource choices, and ratepayers, not investors, take all the risk.

Another key lesson from California is to ensure that resources, especially intermittent and energy resources are accurately accredited. The persistent over counting of solar in particular prior to the implementation of ELCC led to large reductions in the counting of solar once ELCC was introduced, partially contributing to the capacity shortages that California has experienced recently.

Respectfully submitted,

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EXECUTIVE SUMMARY OF CALPINE CORPORATION'S RESPONSES

Immediate:

1. Mandate a reliability standard.
2. Modify the current ORDC to help achieve the standard, e.g., 1-in-10 standard.
3. Continue conservative procurement of reserves at the 6,500-7,500 MW level and allocate some of those costs to intermittent resources to mitigate costs to Load.
4. Expand demand response (DR) capability and require that the deleterious effects of out of market DR deployments on energy prices be accounted for to prevent price reversals.
5. Review Ancillary Service qualification standards to ensure performance matches desired level of long-term reliability.

Long-term:

1. Review and adopt a direct mechanism to ensure that sufficient resources are available to meet reliability standards and give the process time to address concerns.
 - a. Open a Project to review the threat to dispatchable generation caused by out of market subsidies and develop a plan to manage risk to reliability through a rulemaking.
 - b. Adopt a structure like/or similar to the LSE Reliability Obligation described by E3.
2. Design reliability products that meet the long-term reliability needs of the system and refrain from picking winners and losers through discriminatory resource procurement, mandates or payments. Central planning style procurement undermines competitive markets by halting private investment or becomes significantly more expensive because of investor's concerns about future intervention.